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(54) **WELL CONSTRUCTION REAL-TIME TELEMETRY SYSTEM**

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(52) **U.S. Cl.**

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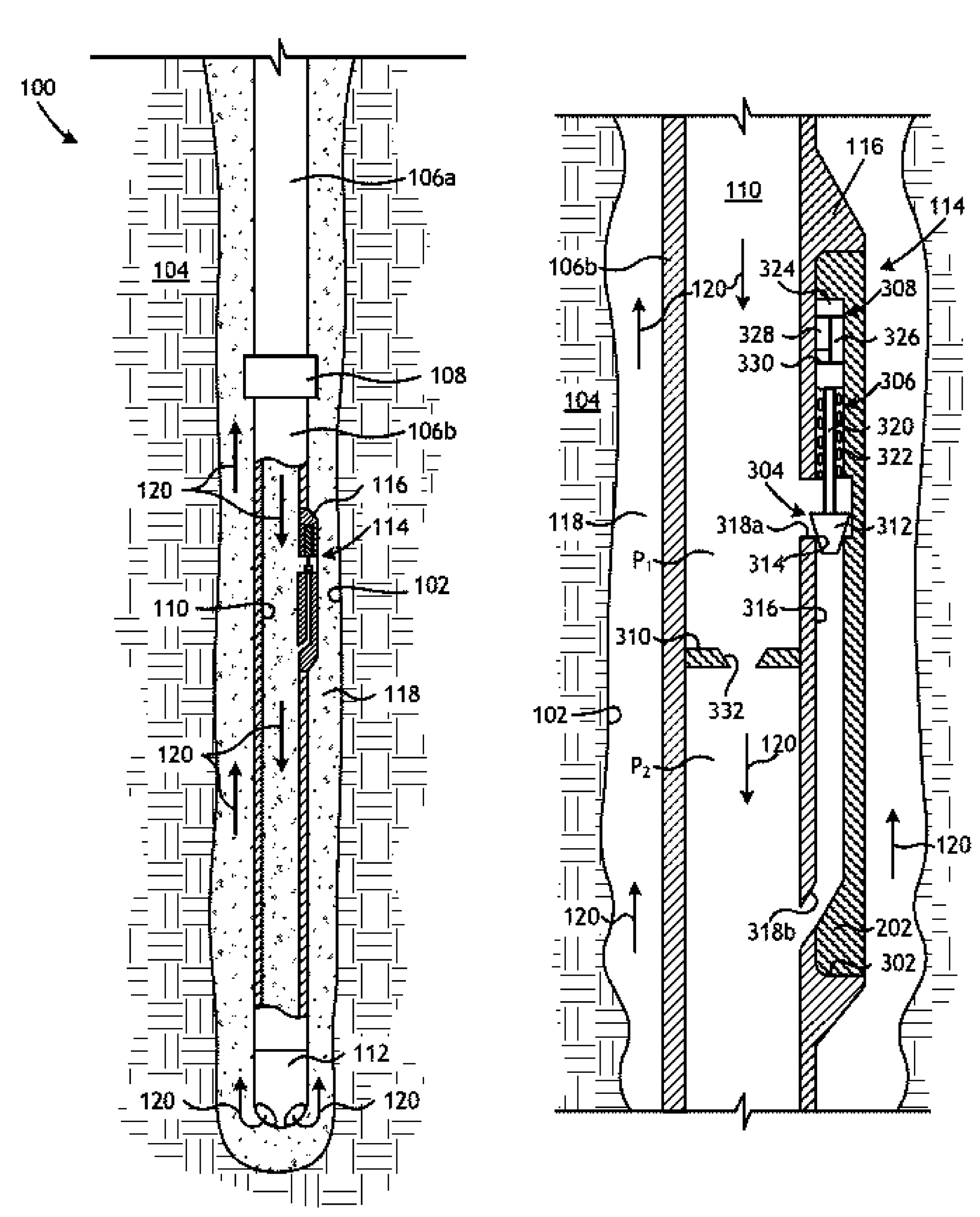
(57) **ABSTRACT**

Downhole assemblies including a plurality of tubular members extendable within a wellbore and defining a through bore. A telemetry device is positioned within a wall of one of the plurality of tubular members and has a secondary flow path defined therethrough and a valve element engageable with a valve seat provided at an upper end of the secondary flow path. The secondary flow path extends between an inlet and an outlet, both of which fluidly communicate with the through bore and are defined in the one of the plurality of tubular members. A flow restrictor is located within the through bore and is axially positioned between the inlet and the outlet of the secondary flow path. The valve element is actuatable to control fluid flow through the secondary flow path to selectively generate a fluid pressure pulse.

24 Claims, 3 Drawing Sheets



(51) **Int. Cl.**

E21B 47/022	(2012.01)
E21B 47/06	(2012.01)
E21B 49/00	(2006.01)

(52) **U.S. Cl.**
CPC ***E21B 47/187*** (2013.01); *E21B 47/022* (2013.01); *E21B 47/06* (2013.01); *E21B 47/065* (2013.01); *E21B 49/00* (2013.01)

(58) **Field of Classification Search**
CPC E21B 47/065; E21B 49/00; E21B 43/123; E21B 34/10; Y10T 29/49405; Y10T 137/7932; Y10T 137/7856
See application file for complete search history.

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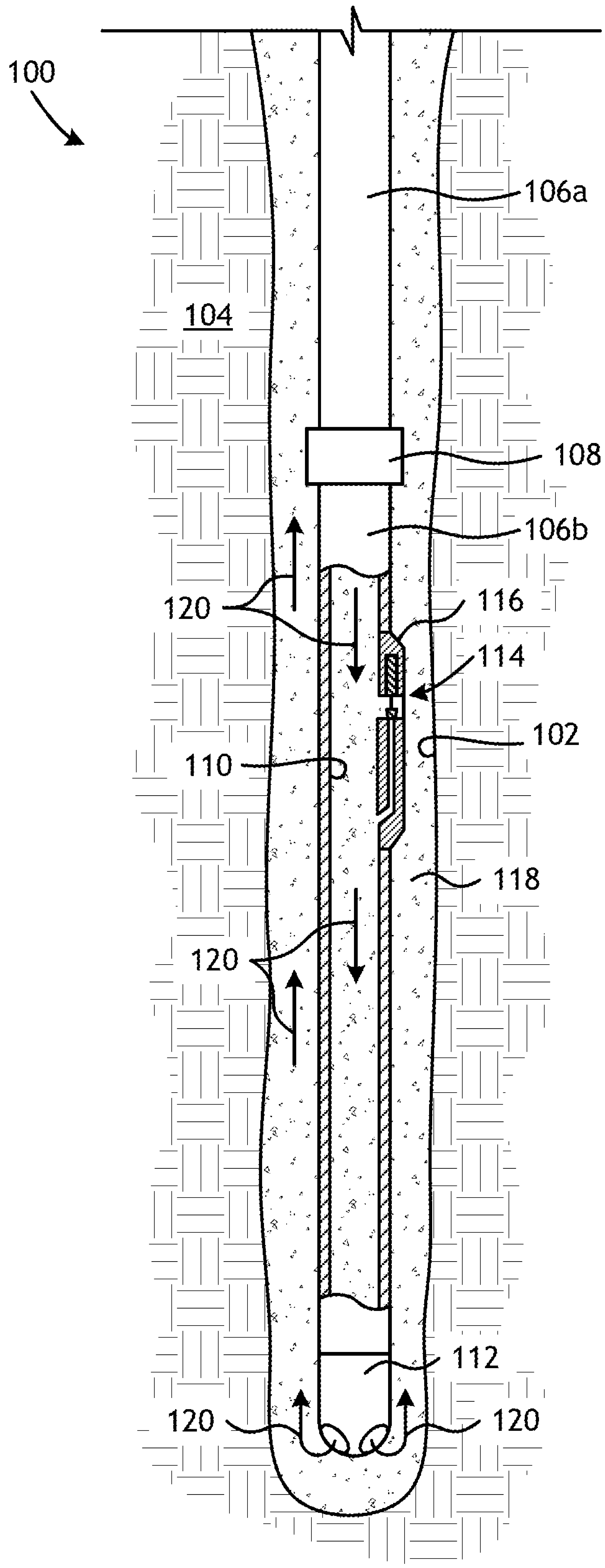


FIG. 1

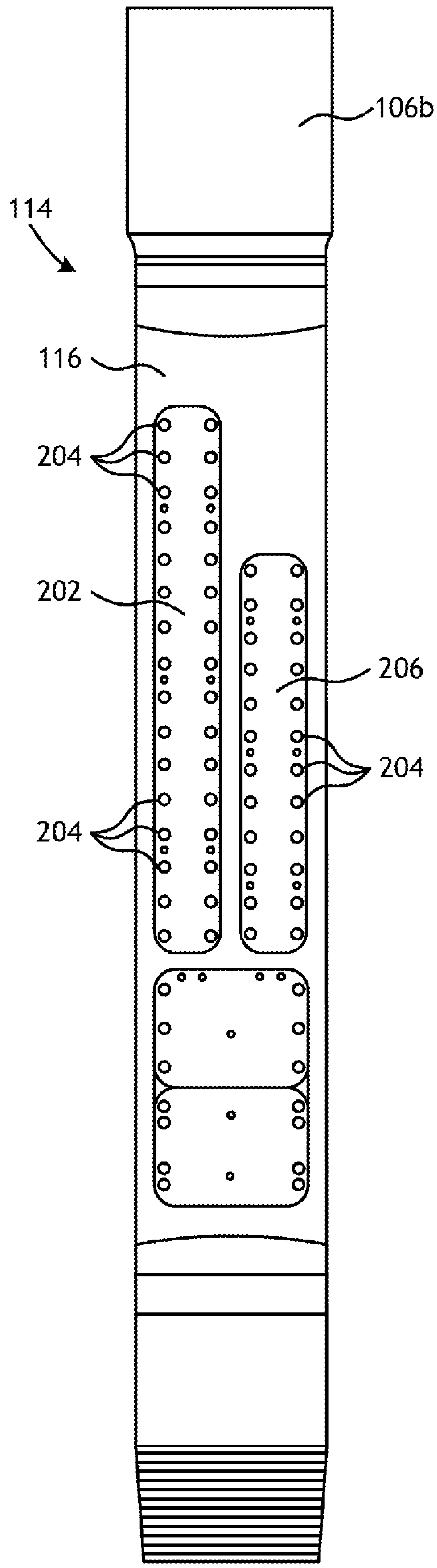


FIG. 2A

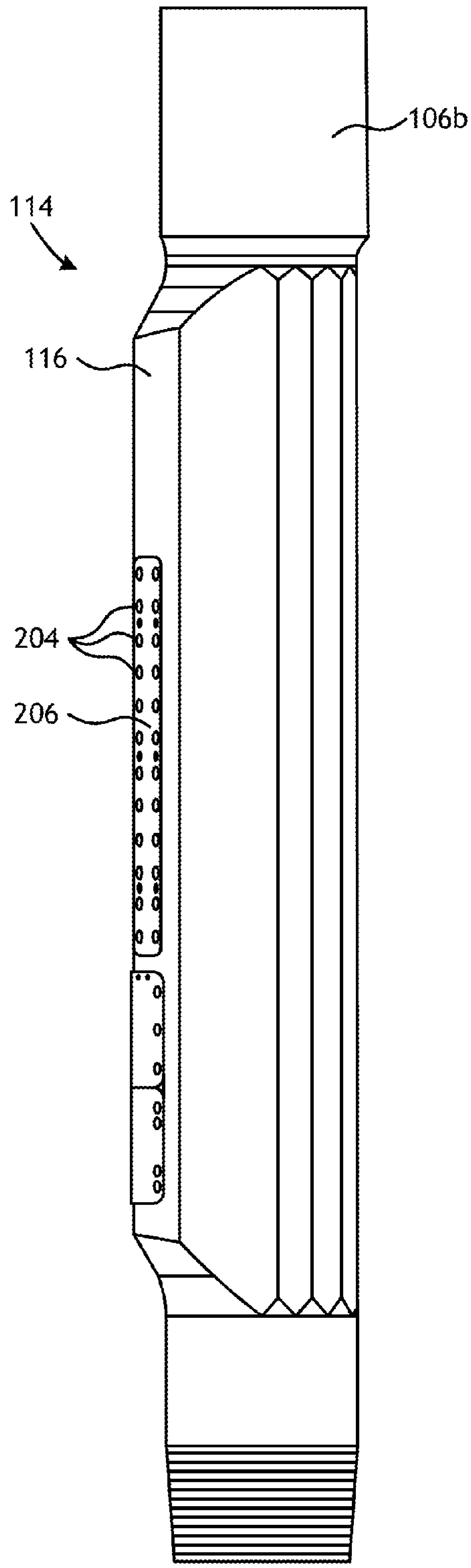


FIG. 2B

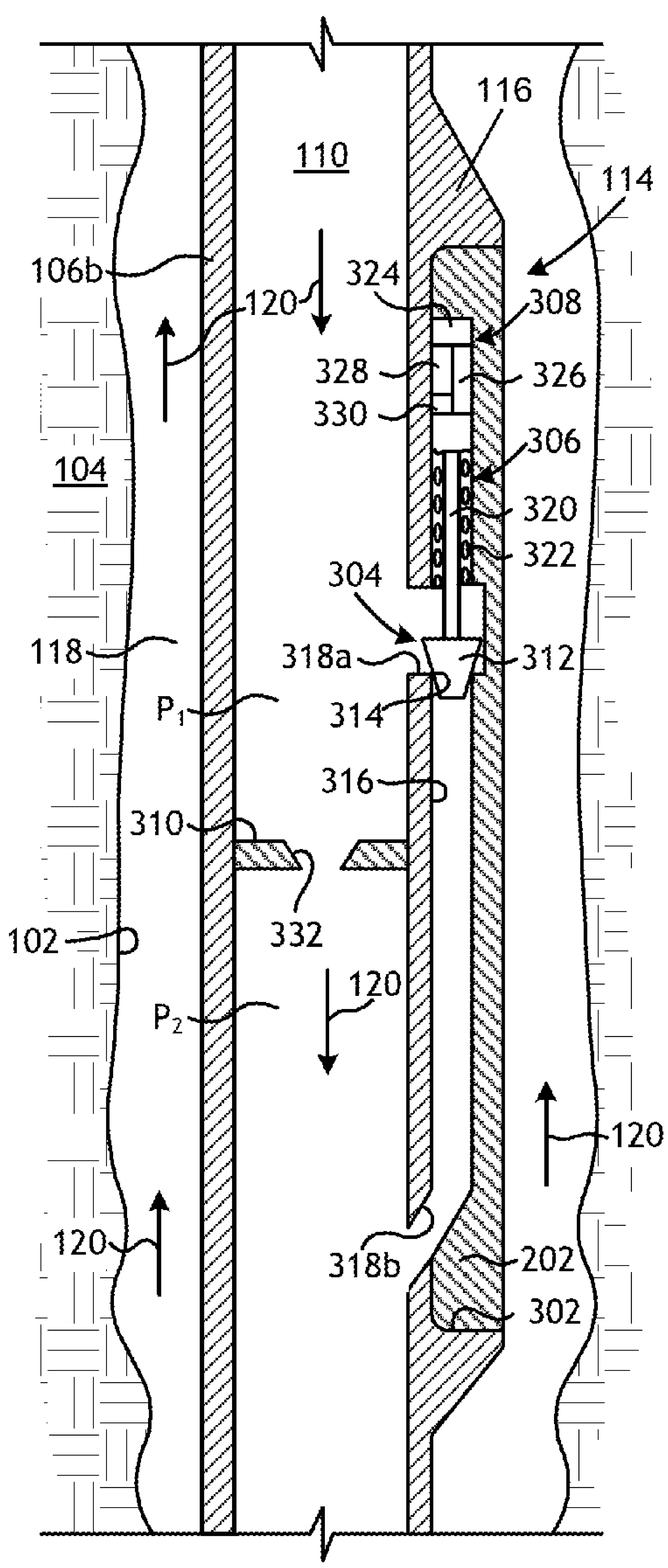
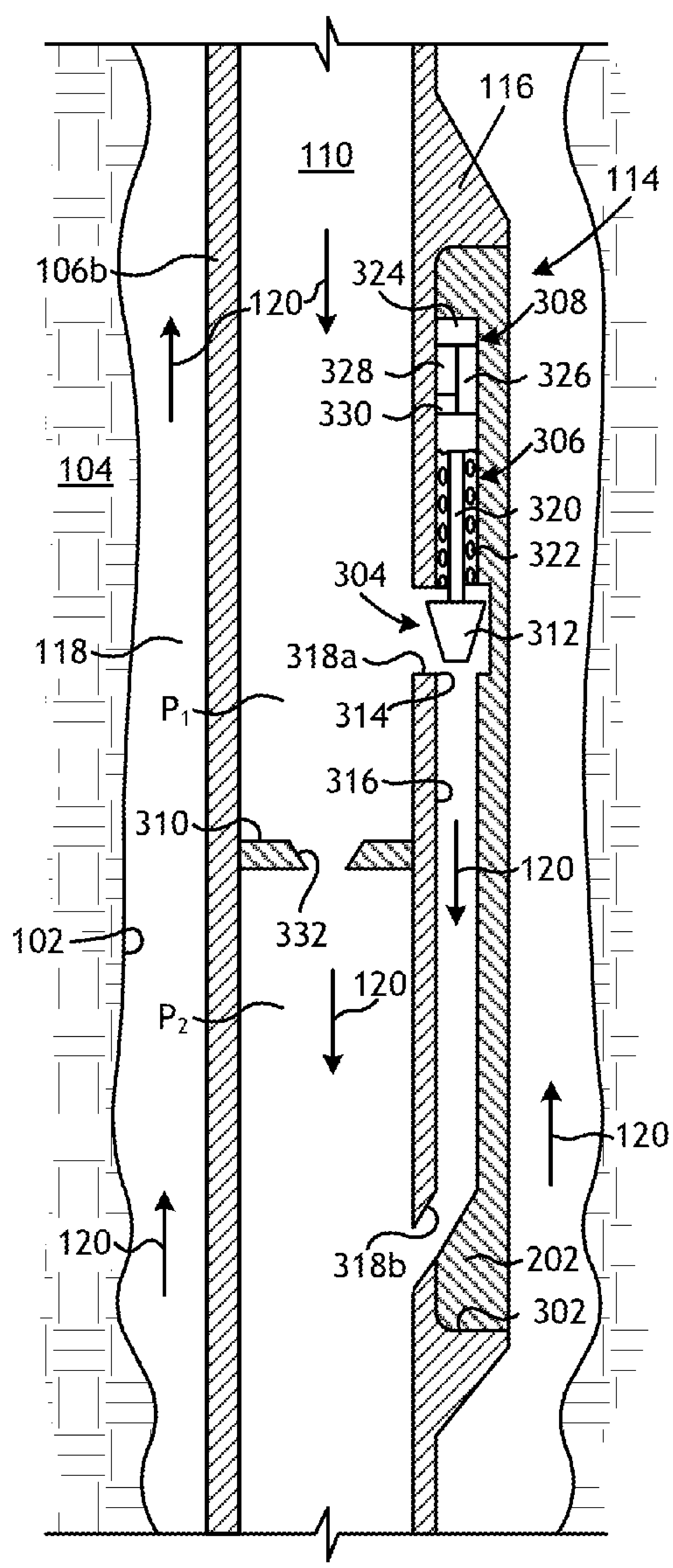

116
110
114
106b
324
308
120
328
326
330
306
104
320
322
304
118
318a
312
P1
314
316
310
332
102
120
P2
120
120
318b
202
302

FIG. 3A


116
110
114
106b
324
308
120
328
326
330
306
104
320
322
304
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118
318a
P1
314
316
310
120
332
102
120
P2
120
120
318b
202
302

FIG. 3B

WELL CONSTRUCTION REAL-TIME TELEMETRY SYSTEM

BACKGROUND

The present disclosure is related to wellbore operations and, more particularly, to fluid-based telemetry devices used in wellbore operations to selectively generate fluid pressure pulses.

In the oil and gas industry, drilling a wellbore, preparing the drilled wellbore for production, and subsequent intervention operations in the completed wellbore each involve the use of a wide range of different specialized equipment. For instance, a drilled wellbore is often lined with bore-lining tubing called "casing" that serves a number of functions, including sealing the wellbore and preventing collapse of the drilled rock formations penetrated by the wellbore. Generally, the casing comprises tubular pipe sections that are coupled together end to end to form a casing string. A series of concentric casing strings can extend from a wellhead to desired depths within the wellbore. Liner is a type of casing that comprises tubular pipe sections coupled end to end but does not extend back to the wellhead. Rather, liner is attached and otherwise sealed to the lower-most section of casing in the wellbore.

After the casing or liner is properly located within the wellbore, cement slurry is commonly pumped into the tubing and back out of the wellbore via the annulus defined between the tubing and the wellbore walls. Once the cement sets, the bore-lining tubing is secured within the wellbore for long-term operation.

A wide range of ancillary equipment is used in both running and locating casing within a wellbore. For example, measuring-while-drilling (MWD) tools are sometimes used to measure various wellbore parameters and guide casing strings to target locations within the wellbore. MWD tools are also able to communicate in real-time with a surface location, thereby providing real-time updates to a well operator of the wellbore parameters measured downhole and the current location and orientation of the casing string within the wellbore. Some MWD tools communicate with the surface location using mud-pulse telemetry, which consists of generating fluid pressure pulses that are transmitted to the surface through a column of fluid within the wellbore. Systems exist to generate 'negative' and 'positive' fluid pressure pulses that can be sensed and interpreted at the surface location.

In running casing into a wellbore, the MWD tool is often disposed in a probe positioned within the casing. This leads to inevitable wear and tear on the MWD tool, primarily through the processes of erosion as fluids circulate around and past the probe within the through bore of the casing. The cost of operating MWD equipment is therefore often determined by the required flow rates and types of fluids circulated within the wellbore. Furthermore, as the through bore of the casing is substantially obstructed by the MWD equipment and probe, it is difficult to pass other equipment through the through bore. For instance, actuating devices, such as hydraulic fracturing balls ("frac balls") or other similar downhole equipment, are often conveyed downhole to actuate a sliding sleeve or valves. The MWD equipment and probe, however, may present a considerable obstacle in reaching the sliding sleeves or valves located below the MWD equipment.

BRIEF DESCRIPTION OF THE DRAWINGS

The following figures are included to illustrate certain aspects of the present disclosure, and should not be viewed as exclusive embodiments. The subject matter disclosed is capable of considerable modifications, alterations, combinations, and equivalents in form and function, without departing from the scope of this disclosure.

FIG. **1** is a schematic diagram of a downhole assembly that may employ the principles of the present disclosure.

FIGS. **2**A and **2**B are enlarged side views of the exemplary telemetry device of FIG. **1**.

FIGS. **3**A and **3**B are enlarged cross-sectional side views of the exemplary telemetry device of FIG. **1** in closed and open positions, respectively.

DETAILED DESCRIPTION

The present disclosure is related to wellbore operations and, more particularly, to fluid-based telemetry devices used in wellbore operations to selectively generate fluid pressure pulses.

The presently disclosed embodiments provide wall-mounted fluid-based telemetry devices, also known as pulser devices, that are able to monitor the deployment of wellbore tubulars while eliminating the need to subsequently mill out the telemetry device. The exemplary wall-mounted telemetry devices may be positioned within an upset portion provided on the wall of a wellbore tubular, which may include casing or drill pipe. As a result, the telemetry devices described herein are not required to be milled or drilled out subsequent to operation, which eliminates the need to mill or drill exotic materials, such as batteries that may power the telemetry devices.

The telemetry devices described herein may also include various sensors and gauges configured to monitor several wellbore parameters including, but not limited to, the inclination and azimuth of the wellbore tubulars, the temperature and pressure in the wellbore environment, and the depth of the wellbore tubulars. Such measured data may be transmitted to the surface in real-time with the telemetry devices using mud-pulse telemetry. Advantageously, the wall-mounted telemetry devices described herein do not require an exit orifice to the annulus defined between the wellbore tubulars and the wellbore wall. Rather, the exemplary telemetry devices discharge fluid back into the main through bore of the assembly. As a result, there are no potential leak paths extending between the through bore and the annulus that might cause future leaks and problems.

Referring to FIG. **1**, illustrated is partial cross-sectional view of a downhole assembly **100** that may employ the principles of the present disclosure, according to one or more embodiments. As illustrated, the downhole assembly **100** may be positioned within a wellbore **102** that penetrates one or more subterranean formations **104**. The downhole assembly **100** may include a plurality of tubular members **106** (two shown as first and second tubular members **106***a* and **106***b*, respectively) extendable within the wellbore **102** and coupled at their ends to each other at appropriate coupling locations **108**. The tubular members **106***a,b* may provide or otherwise define an inner flow passageway or through bore **110** that is able to receive and convey fluids through the downhole assembly **100**. In some embodiments, the through bore **110** extends to a surface location such that fluids introduced into the through bore **110** at the surface are able to reach the downhole assembly **100**.

In the illustrated embodiment, the tubular members **106** are depicted as bore-lining pipes or conduits, such as casing or liner. Accordingly, in at least one embodiment, the plurality of tubular members **106** may comprise a string of casing disposed within the wellbore **102**, and the downhole assembly **100** may be used to undertake a wellbore completion operation, such as cementing the tubular members **106***a,b* in place within the wellbore **102** or aligning a pre-milled window (not shown) with a high side of the wellbore **102**. As illustrated, the second tubular member **106***b* may be the last tubular member **106** in the string of casing as extended into the wellbore **102**. A casing shoe **112** may be coupled to the distal end of the second tubular member **106***b*.

It should be noted that while the downhole assembly **100** is illustrated and generally described herein with respect to tubular members **106** that may comprise casing or liner, the principles of the present disclosure are equally applicable to downhole assemblies that use other types of downhole pipes or conduits. In other embodiments, for instance, the plurality of tubular members **106** may include, but are not limited to, drill pipe and production tubing. Accordingly, in at least one embodiment, the downhole assembly **100** may be used during a drilling operation, such as drilling the wellbore **102**. In such embodiments, the casing shoe **112** may be replaced with a drill bit (not shown) or the like, without departing from the scope of the disclosure.

The downhole assembly **100** may further include a fluid-based telemetry device **114** coupled or otherwise attached to a wall of one of the tubular members **106***a,b*. More particularly, the fluid-based telemetry device **114** (hereafter "the telemetry device **114**") may be disposed within or inside the wall of the second tubular member **106***b* such that the through bore **110** of the second tubular member **106***b* is unobstructed by the telemetry device **114**. In the illustrated embodiment, the telemetry device **114** is depicted as being positioned within or inside an upset portion **116** defined or otherwise provided on the wall of the second tubular member **106***b*. The upset portion **116** may form an integral part of the wall of the second tubular member **106** and otherwise extend radially outward therefrom and into the annulus **118** defined between the tubular members **106** and the wellbore **102** wall. In other embodiments, however, the wall of the second tubular member **106***b* may be sufficiently thick to house the telemetry device **114** without requiring radial expansion of its outer diameter.

The telemetry device **114** may be used for measuring one or more wellbore parameters within the wellbore **102**, and generating fluid pressure pulses to transmit data relating to the measured wellbore parameters to a surface location (not shown). In exemplary operation, a fluid **120** may be circulated through the downhole assembly **100** and, more particularly, into the tubular members **106***a,b* and past the telemetry device **114**. The fluid **120** may exit the tubular members **106***a,b* via the casing shoe **112** and proceed back uphole toward the surface via the annulus **118**. In some embodiments, the fluid **120** may be drilling fluid or "mud" used to help move the downhole assembly **100** to a target location within the wellbore **102**. In other embodiments, the fluid **120** may be a cement used to secure the tubular members **106***a,b* within the wellbore **102** once a target location within the wellbore **102** is reached.

The telemetry device **114** may be configured to continuously or intermittently monitor various wellbore parameters, such as the depth, azimuth, inclination, and tool-face direction of the downhole assembly **100**. Using mud-pulse telemetry, the telemetry device **114** may further be configured to transmit the measured wellbore parameters in real-time to the surface location for consideration by a well operator. Conventional wall-mounted pulsers often discharge fluids into the annulus **118**, which provides a flow path to the annulus **118** and therefore represents a potential leak path into the through bore **110**. In some cases, such flow paths to the annulus **118** in conventional wall-mounted pulsers become plugged with filter cake or other debris derived from the wellbore **102**, and thereby frustrates the operation of such wall-mounted pulsers. The telemetry device **114** described herein, however, discharges the fluid **120** back into the through bore **110**, thereby eliminating the possibility of a leak path to the annulus **118** and ensuring well integrity.

In embodiments where the tubular members **106***a,b* comprise casing, the telemetry device **114** may prove advantageous in measuring the depth, inclination, and tool-face direction of the tubular members **106***a,b*, and thereby help a well operator locate a position of the downhole assembly **100** relative to a high side of a the wellbore **102**. In such embodiments, the downhole assembly **100** may include and otherwise be used to orient a pre-milled window (not shown), for example, with the high side of the wellbore **102**. Moreover, in such embodiments, the telemetry device **114** may be positioned as close as possible to the casing shoe **112** so as to be in an optimal position for monitoring the placement of the tubular members **106***a,b* within the wellbore **102**.

Referring now to FIGS. **2**A and **2**B, with continued reference to FIG. **1**, illustrated are enlarged side views of the telemetry device **114**, according to one or more embodiments. As illustrated, the telemetry device **114** may be arranged within a cartridge **202** (not shown in FIG. **2**B) mounted on or otherwise within the upset portion **116** of the second tubular member **106***b*. In some embodiments, the cartridge **202** may be mechanically fastened to the upset portion **116**, such as by a plurality of bolts **204**. In other embodiments, the cartridge **202** may be secured to the upset portion **116** by other means including, but not limited to, welding, snap rings, an interference fit, adhesives, and any combination thereof. The cartridge **202** may house some or all of the components of the telemetry device **114**, such as the electronics, sensors, and gauges used to operate the telemetry device **114**.

In some embodiments, the telemetry device **114** may further include a power cartridge **206** that may also be mounted on or otherwise within the upset portion **116** and secured thereto with bolts **204**. As illustrated, the power cartridge **206** may be laterally offset from the cartridge **202** and otherwise angularly adjacent the cartridge **202** about the outer radial surface of the upset portion **116**. The power cartridge **206** may house a power source used to provide electrical power to the telemetry device **114**. In some embodiments, for example, the power cartridge **206** may have one or more batteries arranged therein. In other embodiments, however, the power cartridge **206** may be omitted and the power source that powers the telemetry device **114** may be arranged within the cartridge **202**, without departing from the scope of the disclosure.

Referring now to FIGS. **3**A and **3**B, illustrated are enlarged cross-sectional side views of the telemetry device **114**, according to one or more embodiments. More particularly, FIG. **3**A depicts the telemetry device **114** in a closed position, and FIG. **3**B depicts the telemetry device **114** in an open position. As illustrated, the telemetry device **114** is arranged within the wellbore **102** adjacent the subterranean formation **104**. Moreover, the telemetry device **114** is depicted as being positioned or otherwise arranged within or inside a cavity **302** defined within the wall (e.g., the upset portion **116**) of the tubular member **106***b* such that the through bore **110** of the tubular member **106***b* remains unobstructed by the telemetry device **114**. As illustrated, the telemetry device **114** is arranged within the cartridge **202**, which may be releasably mounted within the cavity **302** defined in the upset portion **116**.

The telemetry device **114** may include an operating valve **304**, an actuator **306** coupled to the operating valve **304**, a control system **308** used to control the actuator **306**, and a flow restrictor **310** located within the through bore **110** of the tubular member **106***b*. The operating valve **304** may include a valve element **312** configured to seal against a valve seat **314** provided at an upstream or "upper end" of a secondary flow path **316** defined in the telemetry device **114**. In some embodiments, the operating valve **304** may be generally characterized as a poppet valve. The secondary flow path **316** may extend between an inlet **318***a* and an outlet **318***b*, both being defined in the tubular member **106***b* and configured to allow fluid communication between through bore **110** and the secondary flow path **316**. In some embodiments, the secondary flow path **316** may be defined in or through a portion of the upset portion **116**. In other embodiments, the internal flow path may be defined in or through a portion of the cartridge **202**. In yet other embodiments, the secondary flow path **316** may be defined in or through a combination of the upset portion **116** and the cartridge **202**.

As described in more detail below, the telemetry device **114** may be actuatable to selectively move the valve element **312** in and out of sealing abutment or engagement with the valve seat **314** and thereby generate fluid pressure pulses that may be detectable at a surface location. Moving the valve element **312** may be accomplished by activating the actuator **306**, which may include a shaft **320** coupled to the valve element **312**. In some embodiments, the actuator **306** may be a solenoid-type actuator. In other embodiments, the actuator **306** may be any other type of actuator including, but not limited to, a mechanical actuator, an electrical actuator, an electromechanical actuator, a hydraulic actuator, a pneumatic actuator, and any other device or apparatus that may be able to move the valve element **312** in and out of engagement with the valve seat **314**. In the illustrated embodiment, a return spring **322** may be provided to bias the valve element **312** into sealing abutment with the valve seat **314**. Accordingly, the default position of the valve element **312** may be in engagement with the valve seat **314**.

The control system **308** may be configured to control operation of the actuator **306** and, therefore, the operating valve **304**. In some embodiments, the control system **308** may further include a power source **324** that provides power for operating the actuator **306** and the control system **308**. In some embodiments, the power source **324** may include a conventional battery pack. In other embodiments, the power source **324** may be omitted from the control system **308**, and instead form part of the power cartridge **206**, as described above with reference to FIGS. **2**A-**2**B.

In some embodiments, the control system **308** may further include various sensors **326** and a microprocessor **328**. The sensors **326** may include orientation, geological, and/or physical sensors used to measure certain wellbore parameters. Suitable orientation sensor(s) may include, but are not limited to, an inclinometer, a magnetometer, and a gyroscopic sensor. Suitable geological sensor(s) may include, but are not limited to, a gamma sensor, a resistivity sensor, and a density sensor. Suitable physical sensor(s) may include, but are not limited to, sensors for measuring temperature, pressure, acceleration, and strain parameters.

The microprocessor **328** may include a memory **330** and comprise stacked circular or rectangular printed circuit boards. The memory **330** may be configured to store data and programming instructions executable by the microprocessor **328** to operate the telemetry device **114**. In some embodiments, the data obtained by the sensors **326** may be stored in the memory **330**. In other embodiments, as described below, the data obtained by the sensors **326** may be processed by the microprocessor **328** and encoded into a series of decipherable fluid pressure pulses generated by the telemetry device **114**. Such pressure pulses may be transmitted uphole to a surface location for decoding and consideration by a well operator.

The flow restrictor **310** may be located in the through bore **110** axially between the inlet **318***a* and the outlet **318***b* of the secondary flow path **316**. More particularly, the flow restrictor **310** may be positioned such that the inlet **318***a* is upstream or uphole of the restriction and the outlet **318***b* is downstream or downhole from the flow restrictor **310**. The flow restrictor **310** may be configured to restrict fluid flow and, more particularly, may be configured to restrict fluid flow through the through bore **110**. As a result, a pressure drop or differential may be assumed across the flow restrictor **310** such that fluid pressure P_1 above the flow restrictor **310** may be greater than fluid pressure P_2 below the flow restrictor. Such a pressure drop between P_1 and P_2 may be required to properly operate the telemetry device **114**, as described below.

In some embodiments, the flow restrictor **310** may be made of or otherwise comprise a material that does not require a significant amount of time to mill or drill through and otherwise generates a low amount of cuttings debris. Suitable materials for the flow restrictor **310** include, but are not limited to, aluminum, bronze, a composite material, any combination thereof, and the like. In such embodiments, debris management may no longer present a significant issue, since no steel cuttings are generated in removing the flow restrictor **310** and, therefore, lengthy milling and cleanout trips are substantially eliminated.

Following final operations of the telemetry device **114**, the flow restrictor **310** may be removed from the through bore **110** by milling or drilling through the flow restrictor **310** with a mill or drill bit (not shown) extended into the tubular member **106***b*. With the flow restrictor **310** removed, the through bore **110** may be unobstructed for fluid flow at that location. In some embodiments, the flow restrictor **310** may include or otherwise define a nozzle **332** that generates the required pressure drop across the flow restrictor **310**. In other embodiments, the flow restrictor **310** may comprise a burst disk with a central hole defined therethrough that allows a metered or predetermined amount of fluid flow. As described below, the burst disk may be configured to break or otherwise fail upon assuming a predetermined axial load or fluid pressure.

Exemplary operation of the telemetry device **114** is now provided. A fluid may be conveyed into and through the through bore **110**, as indicated by the arrows **120**. As mentioned above, the fluid **120** may be a drilling fluid or a cement used for various wellbore operations. The fluid **120** may be circulated into the tubular members **106***a,b*, past the telemetry device **114**, and proceed back uphole toward the surface via the annulus **118**. When the fluid **120** enters the through bore **110**, the fluid **120** flows through the flow restrictor **310**, which causes the pressure P_1 to be greater than the pressure P_2 due to the pressure loss assumed across the flow restrictor **310**.

As indicated above, the default position of the operating valve **304** may be the closed position, where the valve element **312** is in sealing abutment with the valve seat **314**. With the operating valve **304** in the closed position, fluid flow along the secondary flow path **316** is substantially prevented. To generate a fluid pressure pulse, a signal may be sent by the microprocessor **328** to the actuator **306**, which results in axial translation of the shaft **320** and corresponding movement of the valve element **312** out of sealing abutment with the valve seat **314**. This places the telemetry device **114** in the open position, as shown in FIG. 3B, and otherwise opens the secondary flow path **316** to allow a portion of the fluid **120** to enter the secondary flow path **316** via the inlet **318***a*. The fluid **120** that flows through the secondary flow path **316** is eventually discharged back into the through bore **110** axially below the flow restrictor **310**. Accordingly, unlike conventional wall-mounted telemetry devices, the telemetry device **114** does not include a potential leak path extending between the through bore **110** and the annulus **118** that might cause future leaks or problems.

Opening the secondary flow path **316** effectively increases the flow area of the telemetry device **114**. Consequently, the pressure P_1 of the fluid **120** above the flow restrictor **310** and upstream of the inlet **318***a* is reduced so that a negative pressure pulse is generated within the through bore **110**, which may be communicated up the through bore **110** and detected at the surface. After a desired period of time, the actuator **306** may be deactivated and the return spring **322** will urge the valve element **312** back into sealing abutment with the valve seat **314**, thereby closing the secondary flow path **316** once again. Closing the secondary flow path **316** reduces the flow area of the telemetry device **114** and simultaneously raises the pressure P_1 of the fluid **120** upstream of the flow restrictor **310**. Again, this pressure change may be detected at the surface. The operating valve **304** may be operated several times to move between closed and open positions and thereby generate a string of fluid pressure pulses that are detectable at the surface. In a known fashion, data relating to wellbore parameters measured by the sensors **326** can be transmitted to the surface by operating the telemetry device **114** as described herein.

In some embodiments, positive fluid pressure pulses may be generated with the telemetry device **114**. This may be achieved by normally holding the valve element **312** out of sealing abutment with the valve seat **314** (or by holding the valve element **312** out of abutment for a certain period of time), such that the secondary flow path **316** is open. In some embodiments, this may be accomplished by replacing the return string **322** with a tension spring (not shown) that urges the valve element **312** away from the valve seat **314**. Operation of the actuator **306** may then act against the force of the tension spring to urge the valve element **312** into sealing abutment with the valve seat **314**. Repeatedly closing the operating valve **304** thus closes the secondary flow path **316** to generate positive pressure pulses within the through bore **110**. Alternatively, the actuator **306** may be maintained in an activated state to hold the valve element **312** clear of the valve seat **314**. However, this will use additional electrical energy and, therefore, may be undesirable.

Once a desired wellbore operation has been undertaken or accomplished, such as orienting a pre-milled window defined in one of the tubular members **106***a,b* (FIG. **1**) relative to a high side of the wellbore **102**, the telemetry device **114** may no longer be needed. At that time, the flow restrictor **310** may be removed from the through bore **110** to eliminate fluid flow obstructions at that location within the through bore **110**. In some embodiments, as mentioned above, this may be accomplished by extending a mill or drill bit (not shown) into the through bore and drilling out the flow restrictor **310**. In other embodiments, a wellbore projectile, such as a cement plug, wellbore dart, or ball, may be introduced into the through bore **110** and flowed to the flow restrictor **310**. In some embodiments, the wellbore projectile may locate and break the flow restrictor **310**. In other embodiments, the wellbore projectile may land on the flow restrictor **310** and the pressure P_1 in the through bore **110** may be increased to place an axial load on the flow restrictor **310** until the flow restrictor **310** fails. In yet other embodiments, the flow restrictor **310** may comprise a burst disk configured to fail upon assuming a predetermined axial load applied from a wellbore projectile or through an increase in the pressure P_1 to a predetermined fluid pressure. With the flow restrictor **310** removed, the through bore **110** may be unobstructed for fluid flow at that location, and thereby provide a larger flow area that permits enhanced flow cementing operations to take place.

The structural location of the telemetry device **114** in the wall of the tubular member **106***b* and otherwise in the upset portion **116** may provide advantages over conventional telemetry devices. Specifically, generation of fluid pressure pulses in the telemetry device **114** may be achieved without restricting the through bore **110**. Accordingly, the fluid **120** may continue to flow through the through bore **110** and the secondary flow path **316** without restriction due to actuation of the telemetry device **114**. Additionally, other downhole tools (not shown) may be conveyed past the telemetry device **114** within the through bore **110**, without the telemetry device **114** causing an obstruction. For example, many types of valves and sleeves exist which are actuated by a wellbore projectile, such as a ball or a dart that is introduced into the through bore **110** at the surface. The wellbore projectile may be able to traverse the through bore **110** without being obstructed by the telemetry device **114**. The wellbore projectile may then pass on to the valve or sleeve where a suitable catcher receives the wellbore projectile and a build-up of fluid pressure behind (i.e., upstream of) the wellbore projectile actuates the valve or sleeve. Some conventional telemetry devices are positioned within the through bore **110** and are required to be drilled or milled out. Drilling or milling out a telemetry device, however, may result in environmental concerns as it is required to drill through exotic materials and batteries associated with the telemetry device. The telemetry device **114** described herein, however, remains out of the through bore **110** and, therefore, is not required to be milled out subsequent to its operation.

Embodiments disclosed herein include:

A. A downhole assembly that includes a plurality of tubular members extendable within a wellbore and defining a through bore for conveying a fluid therein, a telemetry device positioned within a wall of one of the plurality of tubular members, the telemetry device having a secondary flow path defined therethrough and a valve element engageable with a valve seat provided at an upper end of the secondary flow path, wherein the secondary flow path extends between an inlet and an outlet, both of which fluidly communicate with the through bore and are defined in the one of the plurality of tubular members, and a flow restrictor located within the through bore and being axially positioned between the inlet and the outlet of the secondary flow path, wherein the valve element is actuatable to control fluid flow through the secondary flow path to selectively generate a fluid pressure pulse.

B. A fluid-based telemetry device that includes a cartridge removably mounted to a wall of a tubular member that defines a through bore, a secondary flow path defined through at least one of the cartridge and the tubular member and extending between an inlet and an outlet, both of which fluidly communicate with the through bore and are defined in the tubular member, a valve element arranged within the cartridge and engageable with a valve seat provided at an upper end of the secondary flow path, wherein the valve element is actuatable to control fluid flow through the secondary flow path to selectively generate a fluid pressure pulse, and a flow restrictor located within the through bore and axially positioned between the inlet and the outlet of the secondary flow path.

C. A method that includes introducing a downhole assembly into a wellbore, the downhole assembly including a plurality of tubular members that define a through bore and a telemetry device positioned within a wall of one of the plurality of tubular members, conveying a fluid through the through bore and past the telemetry device, the telemetry device providing a secondary flow path that extends between an inlet and an outlet, both of which fluidly communicate with the through bore and are defined in the one of the plurality of tubular members, the telemetry device further including a valve element engageable with a valve seat provided at an upper end of the secondary flow path, generating a pressure drop within the through bore with a flow restrictor axially positioned within the through bore between the inlet and the outlet of the secondary flow path, and actuating the valve element to control fluid flow through the secondary flow path and thereby selectively generating a fluid pressure pulse.

Each of embodiments A, B, and C may have one or more of the following additional elements in any combination: Element 1: wherein the plurality of tubular members is selected from the group consisting of casing, liner, drill pipe, and production tubing. Element 2: wherein the fluid is at least one of a drilling fluid and a cement. Element 3: wherein the through bore of the one of the plurality of tubular members is unobstructed by the telemetry device. Element 4: wherein the telemetry device is positioned within an upset of the one of the plurality of tubular members. Element 5: wherein the telemetry device is arranged within a cartridge removably mounted to the upset. Element 6: further comprising an actuator operatively coupled to the valve element, and a control system that controls movement of the actuator, and thereby controls actuation of the valve element. Element 7: wherein the control system comprises one or more sensors selected from the group consisting of an orientation sensor, a geological sensor, and a physical sensor. Element 8: wherein the flow restrictor comprises a material selected from the group consisting of aluminum, bronze, a composite, and any combination thereof. Element 9: wherein the flow restrictor comprises a burst disk.

Element 10: wherein the cartridge is positioned within an upset provided on the wall of the tubular member. Element 11: wherein the through bore is unobstructed by the valve element and the secondary flow path. Element 12: further comprising an actuator arranged within the cartridge and operatively coupled to the valve element, and a control system arranged within the cartridge to control movement of the actuator and thereby control actuation of the valve element. Element 13: wherein the control system comprises a sensor selected from the group consisting of an inclinometer, a magnetometer, a gyroscopic sensor, a gamma sensor, a resistivity sensor, a density sensor, a temperature sensor, a pressure sensor, an acceleration sensor, and a strain sensor.

Element 14: wherein conveying the fluid through the through bore and past the telemetry device comprises conveying the fluid through the through bore unobstructed by the telemetry device. Element 15: wherein actuating the valve element comprises moving the valve element with an actuator operatively coupled to the valve element, and controlling movement of the actuator with a control system. Element 16: further comprising obtaining measurement data of one or more wellbore parameters with one or more sensors included in the telemetry device, the one or more sensors being selected from the group consisting of an orientation sensor, a geological sensor, and a physical sensor, actuating the valve element to generate fluid pressure pulses corresponding to the measurement data, and receiving the fluid pressure pulses at a surface location. Element 17: further comprising aligning a pre-milled window defined in the plurality of tubular members with a high side of the wellbore based on the measurement data obtained by the one or more sensors. Element 18: wherein actuating the valve element to control fluid flow through the secondary flow path comprises moving the valve element to an open position and thereby allowing a portion of the fluid from the through bore to enter the secondary flow path via the inlet, and discharging the portion of the fluid back into the through bore via the outlet. Element 19: further comprising removing the flow restrictor from the through bore. Element 20: wherein removing the flow restrictor from the through bore comprises milling out the flow restrictor with a mill or drill bit extended into the through bore, the flow restrictor comprising a material selected from the group consisting of aluminum, bronze, a composite, and any combination thereof. Element 21: wherein removing the flow restrictor from the through bore comprises introducing a wellbore isolation device into the through bore, landing the wellbore isolation device on the flow restrictor, and breaking the flow restrictor with the wellbore isolation device. Element 22: wherein the flow restrictor is a burst disk and removing the flow restrictor from the through bore comprises increasing a fluid pressure within the through bore to a predetermined fluid pressure, and breaking the burst disk upon assuming the predetermined fluid pressure.

By way of non-limiting example, exemplary combinations applicable to A, B, C include: Element 4 with Element 5; Element 6 with Element 7; Element 16 with Element 17; Element 19 with Element 20; Element 19 with Element 21; and Element 19 with Element 22.

Therefore, the disclosed systems and methods are well adapted to attain the ends and advantages mentioned as well as those that are inherent therein. The particular embodiments disclosed above are illustrative only, as the teachings of the present disclosure may be modified and practiced in different but equivalent manners apparent to those skilled in the art having the benefit of the teachings herein. Furthermore, no limitations are intended to the details of construction or design herein shown, other than as described in the claims below. It is therefore evident that the particular illustrative embodiments disclosed above may be altered, combined, or modified and all such variations are considered within the scope of the present disclosure. The systems and methods illustratively disclosed herein may suitably be practiced in the absence of any element that is not specifically disclosed herein and/or any optional element disclosed herein. While compositions and methods are described in terms of “comprising,” “containing,” or “including” various components or steps, the compositions and methods can also “consist essentially of” or “consist of” the various components and steps. All numbers and ranges disclosed above may vary by some amount. Whenever a numerical range with a lower limit and an upper limit is disclosed, any number and any included range falling within the range is specifically disclosed. In particular, every range of values (of the form, “from about a to about b,” or, equivalently, “from approximately a to b,” or, equivalently, “from approximately a-b”) disclosed herein is to be understood to set forth every number and range encompassed within the broader range of values. Also, the terms in the claims have their plain, ordinary meaning unless otherwise explicitly and clearly defined by the patentee. Moreover, the indefinite articles "a" or "an," as used in the claims, are defined herein to mean one or more than one of the element that it introduces. If there is any conflict in the usages of a word or term in this specification and one or more patent or other documents that may be incorporated herein by reference, the definitions that are consistent with this specification should be adopted.

As used herein, the phrase "at least one of" preceding a series of items, with the terms "and" or "or" to separate any of the items, modifies the list as a whole, rather than each member of the list (i.e., each item). The phrase "at least one of" allows a meaning that includes at least one of any one of the items, and/or at least one of any combination of the items, and/or at least one of each of the items. By way of example, the phrases "at least one of A, B, and C" or "at least one of A, B, or C" each refer to only A, only B, or only C; any combination of A, B, and C; and/or at least one of each of A, B, and C.

The use of directional terms such as above, below, upper, lower, upward, downward, left, right, uphole, downhole and the like are used in relation to the illustrative embodiments as they are depicted in the figures, the upward direction being toward the top of the corresponding figure and the downward direction being toward the bottom of the corresponding figure, the uphole direction being toward the surface of the well and the downhole direction being toward the toe of the well.

What is claimed is:

1. A downhole assembly, comprising:

a plurality of tubular members extendable within a wellbore and defining a through bore for conveying a fluid therein;

a telemetry device positioned within a wall of one of the plurality of tubular members and providing a secondary flow path having an inlet and an outlet, the inlet and the outlet each fluidly connecting the secondary flow path to the through bore, the telemetry device further providing a valve element engageable with a valve seat provided at an upper end of the secondary flow path; and

a flow restrictor located within the through bore and being axially positioned between the inlet and the outlet of the secondary flow path,

wherein the valve element is actuatable to control fluid flow through the secondary flow path to selectively generate a fluid pressure pulse.

2. The downhole assembly of claim **1**, wherein the plurality of tubular members is selected from the group consisting of casing, liner, drill pipe, and production tubing.

3. The downhole assembly of claim **1**, wherein the fluid is selected from the group consisting of a drilling fluid, a cement, and combination thereof.

4. The downhole assembly of claim **1**, wherein the through bore of the one of the plurality of tubular members is unobstructed by the telemetry device.

5. The downhole assembly of claim **1**, wherein the telemetry device is positioned within an upset portion of the one of the plurality of tubular members.

6. The downhole assembly of claim **5**, wherein the telemetry device is arranged within a cartridge removably mounted to the upset portion.

7. The downhole assembly of claim **1**, further comprising:

an actuator operatively coupled to the valve element; and

a control system that controls movement of the actuator, and thereby controls actuation of the valve element.

8. The downhole assembly of claim **7**, wherein the control system comprises one or more sensors selected from the group consisting of an orientation sensor, a geological sensor, and a physical sensor.

9. The downhole assembly of claim **1**, wherein the flow restrictor comprises a material selected from the group consisting of aluminum, bronze, a composite, and any combination thereof.

10. The downhole assembly of claim **1**, wherein the flow restrictor comprises a burst disk.

11. A fluid-based telemetry device, comprising:

a cartridge removably mounted to a wall of a tubular member that defines a through bore;

a secondary flow path defined through at least one of the cartridge and the tubular member and extending between an inlet fluidly connecting a first end of the secondary flow path to the through bore and an outlet fluidly connecting a second end of the secondary flow path to the through bore;

a valve element arranged within the cartridge and engageable with a valve seat provided at an upper end of the secondary flow path, wherein the valve element is actuatable to control fluid flow through the secondary flow path to selectively generate a fluid pressure pulse; and

a flow restrictor located within the through bore and axially positioned between the inlet and the outlet of the secondary flow path.

12. The fluid-based telemetry device of claim **11**, wherein the cartridge is positioned within an upset portion provided on the wall of the tubular member.

13. The fluid-based telemetry device of claim **11**, wherein the through bore is unobstructed by the valve element and the secondary flow path.

14. The fluid-based telemetry device of claim **11**, further comprising:

an actuator arranged within the cartridge and operatively coupled to the valve element; and

a control system arranged within the cartridge to control movement of the actuator and thereby control actuation of the valve element.

15. The fluid-based telemetry device of claim **14**, wherein the control system comprises a sensor selected from the group consisting of an inclinometer, a magnetometer, a gyroscopic sensor, a gamma sensor, a resistivity sensor, a density sensor, a temperature sensor, a pressure sensor, an acceleration sensor, and a strain sensor.

16. A method, comprising:

introducing a downhole assembly into a wellbore, the downhole assembly including a plurality of tubular members that define a through bore and a telemetry device positioned within a wall of one of the plurality of tubular members;

conveying a fluid through the through bore and past the telemetry device, the telemetry device providing a secondary flow path having an inlet and an outlet, the inlet and the outlet each fluidly connecting the through bore to the secondary flow path, the telemetry device further including a valve element engageable with a valve seat provided at an upper end of the secondary flow path;

generating a pressure drop within the through bore with a flow restrictor axially positioned within the through bore between the inlet and the outlet of the secondary flow path; and actuating the valve element to control fluid flow through the secondary flow path and thereby selectively generating a fluid pressure pulse.

17. The method of claim **16**, wherein conveying the fluid through the through bore and past the telemetry device comprises conveying the fluid through the through bore unobstructed by the telemetry device.

18. The method of claim **16**, wherein actuating the valve element comprises:

moving the valve element with an actuator operatively coupled to the valve element; and

controlling movement of the actuator with a control system.

19. The method of claim **16**, further comprising:

obtaining measurement data of one or more wellbore parameters with one or more sensors included in the telemetry device, the one or more sensors being selected from the group consisting of an orientation sensor, a geological sensor, and a physical sensor;

actuating the valve element to generate fluid pressure pulses corresponding to the measurement data; and

receiving the fluid pressure pulses at a surface location.

20. The method of claim **19**, further comprising aligning a pre-milled window defined in the plurality of tubular members with a high side of the wellbore based on the measurement data obtained by the one or more sensors.

21. The method of claim **16**, wherein actuating the valve element to control fluid flow through the secondary flow path comprises:

moving the valve element to an open position and thereby allowing a portion of the fluid from the through bore to enter the secondary flow path via the inlet; and

discharging the portion of the fluid back into the through bore via the outlet.

22. The method of claim **16**, further comprising removing the flow restrictor from the through bore.

23. The method of claim **22**, wherein removing the flow restrictor from the through bore comprises milling out the flow restrictor with a mill or drill bit extended into the through bore, the flow restrictor comprising a material selected from the group consisting of aluminum, bronze, a composite, and any combination thereof.

24. The method of claim **22**, wherein the flow restrictor is a burst disk and removing the flow restrictor from the through bore comprises:

increasing a fluid pressure within the through bore to a predetermined fluid pressure; and

breaking the burst disk upon assuming the predetermined fluid pressure.

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